Development of Enhanced Oil Recovery Techniques

Projects supported in part
by the Alberta/Canada
Energy Resources
Research Fund

1987
Edmonton

Alberta
ENERGY
Scientific and Engineering
Services and Research Division

Pub. No. I/185

ISBN: 0-86499-470-2

Disclaimer

The contents of this publication are based on the information and data obtained from, and the results and conclusions of, research projects conducted by independent researchers with financial assistance from the Alberta/Canada Energy Resources Research Fund.

The contents of this publication do not necessarily reflect the views of the Government of Alberta, its officers, employees or agents or of the Alberta/Canada Energy Resources Research Fund Committee.

Neither the Government of Alberta nor its officers, employees or agents makes any warranty, express or implied, representation or otherwise, in respect of, or assumes any liability for, the contents of this publication.

Foreword

Since 1976, numerous projects have been initiated in Alberta by industry and by academic research institutions which are aimed at better utilization of Alberta's energy resources.

These research, development and demonstration efforts were funded by the Alberta/Canada Energy Resources Research Fund (A/CERRF), which was established as a result of the 1974 agreement on oil prices between the federal government and the producing provinces.

Responsibility for applying and administering the fund rests with the A/CERRF Committee, made up of senior Alberta and federal government officials.

A/CERRF program priorities have focused on coal, energy conservation and renewable energy and conventional energy resources. Administration for the program is provided by staff within the Scientific and Engineering Services and Research Division of Alberta Energy.

In order to make research results available to industry and others who can use the information, highlights of studies are reported in a series of technology transfer booklets. For more information about other publications in the series, please refer to page 13.

Development of Enhanced Oil Recovery Techniques

The amount of crude oil that may be recovered from a reservoir under natural pressure — called primary recovery — is relatively small. It may be less than five per cent for heavy viscous crude oils and 40 per cent or more for light crudes. In Alberta, primary recovery rates average about 22 per cent of reservoir volumes.

To extract more oil, several enhanced recovery techniques have been developed and are being used in Alberta. They include water flooding, gas injection and hydrocarbon solvent flooding. Some of these methods are more suitable than others for particular reservoirs and some cost less than others, but all of them are capable of achieving acceptable levels of recovery. Water flooding is especially popular because of its lower cost; it is used 10 times as often as other methods.

Despite current usage, however, it has been estimated that even if widespread use of enhanced recovery processes did occur in Alberta, billions of barrels of crude oil would still remain in the ground.

During the late 1970s, some advanced or improved processes capable of higher recovery rates were tried in laboratory and field trials, primarily in the U.S. They included the use of polymers, surfactants and alkaline mixtures in water floods, as well as steam, in situ combustion and the use of non-hydrocarbon gases, such as carbon dioxide. While some of these processes have shown some promise on a small scale, they are relatively expensive and remain unproven on a commercial scale. Nevertheless, some oil industry observers have predicted that an additional 300 to 475 million m^3 of oil could be recovered if advanced recovery processes were widely used in Canada's oil fields. This would represent a 40 per cent gain over primary recovery or primary recovery assisted by water flooding. For this reason, A/CERRF-supported investigations were carried out over an eight-year period to determine which processes might be applicable in Alberta.

Investigations of Advanced Oil Recovery Methods

In 1976, the Petroleum Recovery Institute (PRI), a non-profit organization established 10 years earlier as a joint venture between the Alberta government and the petroleum industry to develop improved methods of oil and gas recovery, was contracted by A/CERRF to undertake laboratory studies of several advanced crude oil recovery methods. Some of these methods were also investigated on a larger scale by PRI's Applications Division in oil field trials, which were limited to sandstone reservoirs.

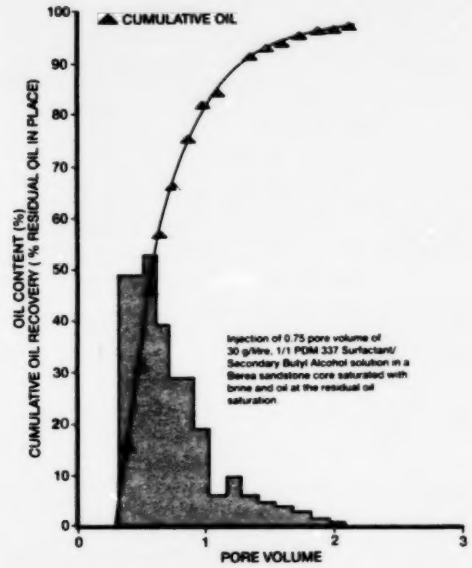
Surfactant Sorption Studies

In an oil displacement process, the amount of oil left as a residual in the reservoir varies inversely with the viscous force that can be applied. This is a function of interfacial tension and the pressure gradient.

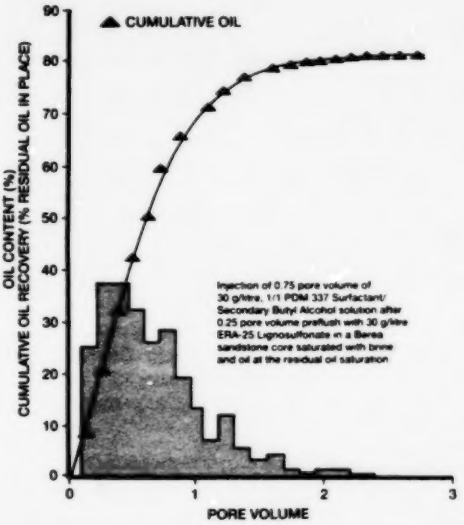
If it is not possible to increase the pressure gradient, then the only way to increase the viscous force is to decrease the interfacial tension by using surfactants, which form microemulsions with the oil. Although surfactants can reduce interfacial tension by a factor of 25 000, their effectiveness can be reduced by adsorption on to rock surfaces, retention in the oil phase or by interaction with brine that is present in the reservoir. Consequently, PRI's investigations were aimed at overcoming these losses.

To simulate reservoir conditions on a laboratory scale, all testing was done using Berea sandstone cores containing brine, and oil at its residual concentration. Test methods were developed to measure surfactant behaviour and recovery. While the experiments confirmed that substantial amounts of surfactant are lost because they were trapped in the immobile oil phase, and measured losses were sensitive to changes in experimental conditions, work with lignosulphonates produced some encouraging results. By first flushing the cores with lignosulphonates, the researchers found that oil recovery rates could be improved, and the lignosulphonate behaved as a co-surfactant rather than as a "sacrificial" substance that was preferentially adsorbed on reservoir rock surfaces, as postulated by earlier investigations.

Effect of a Lignosulfonate Preflush on Residual Oil Recovery


CUMULATIVE OIL
OIL CONTENT (%)
CUMULATIVE OIL RECOVERY (% RESIDUAL OIL IN PLACE)
PORE VOLUME
Injection of 0.75 pore volume of 30 g/litre, 1/1 PDM 337 Surfactant/ Secondary Butyl Alcohol solution in a Berea sandstone core saturated with brine and oil at the residual oil saturation

Recovery of the residual oil in place increased from 82 per cent to 97 per cent when a lignosulfonate preflush was used.


CUMULATIVE OIL
OIL CONTENT (%)
CUMULATIVE OIL RECOVERY (% RESIDUAL OIL IN PLACE)
PORE VOLUME
Injection of 0.75 pore volume of 30 g/litre, 1/1 PDM 337 Surfactant/ Secondary Butyl Alcohol solution after 0.25 pore volume preflush with 30 g/litre ERA-25 Lignosulfonate in a Berea sandstone core saturated with brine and oil at the residual oil saturation

(Source: *Laboratory Evaluation of Lignosulfonates As Sacrificial Adsorbates in Surfactant Flooding*, Novosad, J., L. Baxter and D. Moon. Report 1983-1, Petroleum Recovery Institute, March 1983.)

Displacement Phenomena at Low Interfacial Tensions

Properties of surfactant systems were studied to better understand the role they play in enhanced oil recovery (EOR) systems. The basic phase behaviour and component partitioning of high concentration surfactant systems were studied, as were the salinity tolerance characteristics of various anionic surfactant and co-surfactant mixtures. From these results, models were developed to describe the interplay of such forces as viscosity, gravity and capillary action when water is used to displace residual oil in laboratory simulations of reservoirs.

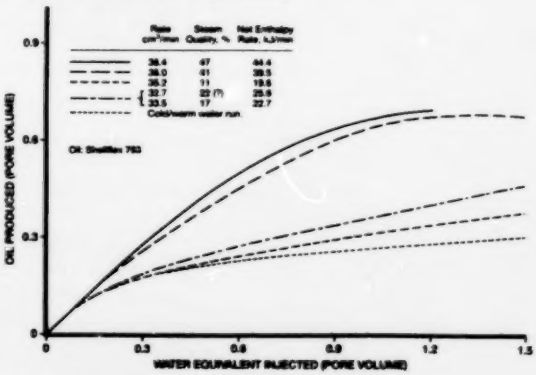
Several promising formulations of surfactants and co-surfactants were developed for use with brines containing two to 16 per cent total dissolved solids, where eight per cent is typical of Alberta reservoirs.

Heavy Oil Recovery by Steam Flooding

In heavy oil operations, approximately 90 per cent of the original oil in place remains unrecovered after extraction by primary recovery methods, especially if the viscous oil is underlain by a bottom water zone. One promising method of increasing the mobility of heavy oil is to heat it with steam. However, the value of thermal recovery methods is difficult to assess, particularly in the field, because contact between oil and steam at elevated temperatures can lead to complex mass transport phenomena, physical changes and chemical reactions that can mask the results.

To provide a better understanding of these various phenomena, PRI researchers undertook numerous well-defined and controlled experiments in the laboratory. They used high-temperature, high-pressure equipment to measure the relative permeabilities of oil-water and oil-steam mixtures at temperatures of 300°C and pressures up to 140 atmospheres. In these experiments, as in much of the work in this project, PRI staff designed and

Effect of Steam Quality on Oil Recovery (at medium flooding rates)



In laboratory studies of steam flooding, oil recovery improved as the steam quality increased.

(Source: *Physical Model Study of Inverted Seven Spot Steamfloods in a Pool Containing a Lloydminster-Type Heavy Oil*, Singhal, A.K. Report RR-38, Petroleum Recovery Institute, November 1978.)

built unique laboratory-scale equipment to conduct their investigations, some of which has subsequently become more widely used within the petroleum industry. One such device, a backpressure regulator developed to improve the accuracy of high-pressure experiments, was eventually marketed to the industry; more than 50 units were sold by PRI.

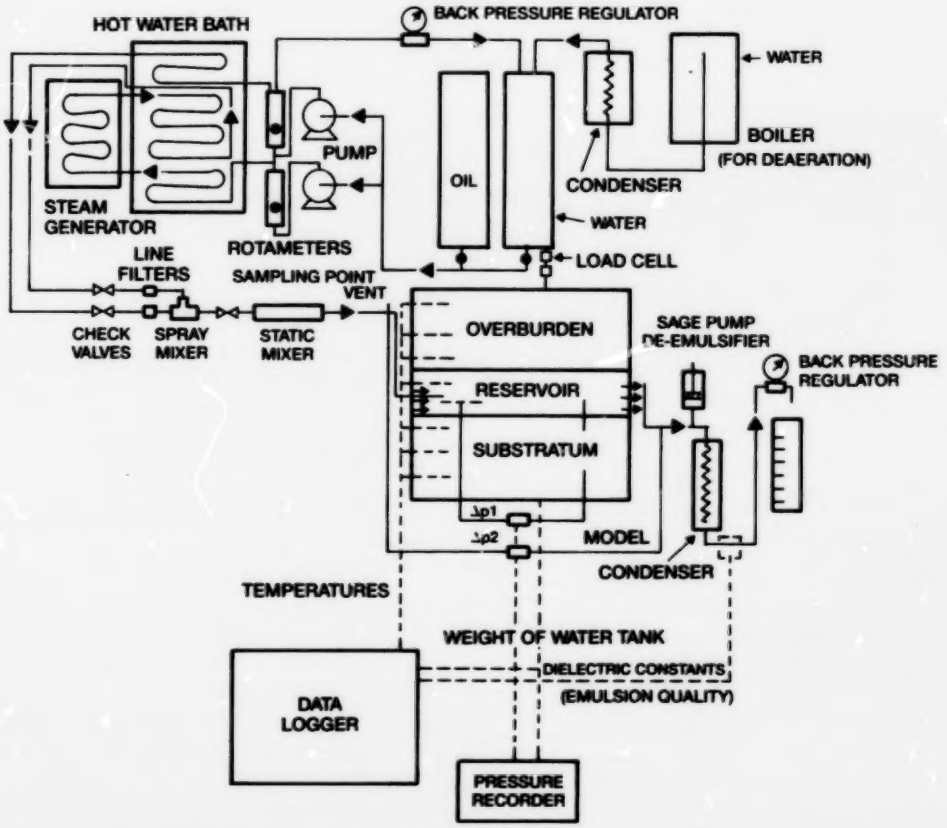
PRI researchers also built a low-pressure, three-dimensional, triangular-shaped model of a heavy oil reservoir employing coarse river sand and glass beads. It represented half of an inverted seven-spot well pattern.

More than 50 tests were carried out with the steam-flooding model to obtain data on such phenomena as the sensitivity of oil recovery to steam injection rate, the roles of gravity overriding of steam and underrunning of condensate water and water coning. It was learned that in a steam-drive process, the quality of the injected steam and the extent of the steam zone in the reservoir have a large influence on the oil recovery rate. The model was refined to accommodate the presence of bottom water, and sufficient data were generated to develop a commercial-scale, numerical simulator, which was used in conjunction with various field measurements to devise five steam-flooding options for a pilot trial at the Bodo Upper Mannville B Pool.

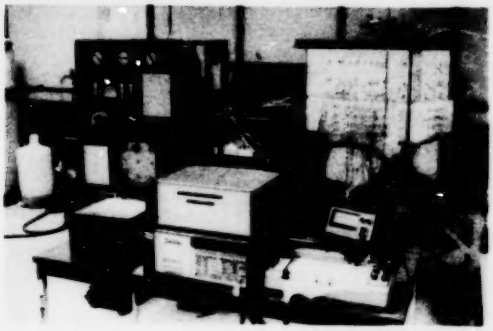
By gathering geological and petrophysical information about the pool, followed by history matching of pilot tests, oil recovery process designs were prepared, which indicated steam flooding could be profitable in this particular oil field. The information was provided to the field operator for consideration.

In conjunction with the steam-flooding project, a high-temperature, high-pressure phase behaviour apparatus was designed and built to obtain measurements of oil/steam/carbon dioxide mixtures. It is capable of operating at 350°C and pressures up to 45 000 kPa.

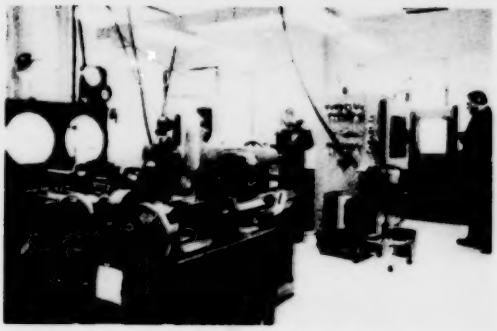
Schematic Diagram of Experimental Steam Flood Apparatus



(Source: *Laboratory Simulation of Steam Drive Process*, Ma.V., B.B. Maini and T. Okazawa, Report 1983-5, Petroleum Recovery Institute, November 1983.)



In this physical model of an unconsolidated sand reservoir, steam was used to displace heavy oil.



High-temperature, high-pressure equipment is used in the heavy oil laboratory.

Oil Recovery by Carbon Dioxide and Sulphur Dioxide Flooding

One way to remove capillary and interfacial forces, and allow advancing and driving fluids to sweep oil from every region of a reservoir, would be to use a solvent which is miscible with the reservoir oil.

In the past, miscible recovery has been achieved with liquid petroleum gas, but it is more highly prized as a fuel. Carbon dioxide has been used, too, but only at high pressure. Sulphur dioxide has seen some limited use, but it tends to be restricted to high-temperature conditions. Researchers at PRI concluded that combinations of carbon dioxide (CO_2) and sulphur dioxide (SO_2) might be useful at lower temperatures and pressure and, therefore, have wider appeal in the field. Ultimately, their research efforts led to a process which was patented in the U.S.

Initially, phase behaviour and fluid properties studies were made of systems comprising CO_2 and low molecular weight hydrocarbons, ranging from n-pentane (nC_5) to n-hexadecane (nC_{16}), as well as $CO_2/SO_2/nC_{16}$ systems at various temperatures and pressures. Results from this work were used to develop procedures for predicting the physical properties of CO_2-crude oil systems.

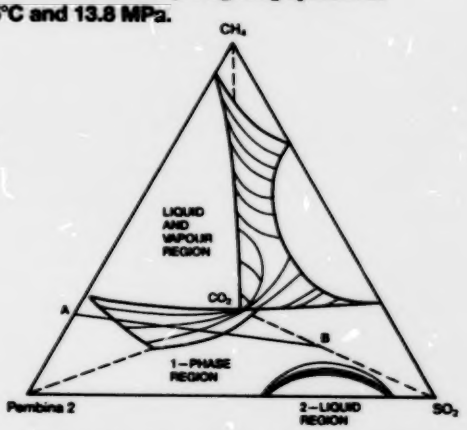
The phase behaviour of nC_5-nC_{16} with CO_2, SO_2 and methane (CH_4) was studied sufficiently to draw several conclusions: 1) it appeared that CO_2 and SO_2 mixtures were good solvents for miscible flooding; 2) CH_4 in the oil phase can improve the miscibility of SO_2 with oil when the reservoir temperature is low and the oil is rich in heavy ends; 3) mixtures of CH_4 and SO_2 can be used as miscible oil recovery agents at high temperature; and 4) several mixing rules were proposed for predicting the densities and viscosities of binary mixtures when the properties of the individual components are known.

When Pembina Cardium stock-tank oil was used with CO_2, SO_2 and CH_4 systems at 45°C and 13.8 MPa pressure, results were very similar to those obtained with low molecular weight oils.

These experiments demonstrated that CO_2/SO_2 mixtures can be miscible with oil when neither CO_2 nor SO_2 alone is miscible. Also, SO_2 increases the extent of oil swelling, which should result in a higher oil recovery rate, and CO_2/SO_2 mixtures can be formulated so that the density and viscosity of the flooding agent closely match those of the oil to allow an improved sweep efficiency.

When core displacement studies were made of nC_5-nC_{16} synthetic oils and carbon dioxide in unfired Berea sandstone, recovery rates of approximately 90 per cent were recorded. The need for displacement data led to the construction of a titanium displacement apparatus that was capable of resisting corrosion caused by carbon dioxide and/or sulphur dioxide.

Phase diagram of a Pembina Cardium Stock-Tank Oil/CH_4/CO_2/SO_2 system at 45°C and 13.8 MPa.



(Source: *Phase Equilibrium and Fluid Properties of Pembina Cardium Stock-Tank Oil/Methane/Carbon Dioxide/Sulphur Dioxide Mixtures*, Sayegh, S.G., J. Najman and B. Hlavacek, Report 81-3, Petroleum Recovery Institute, January 1981.)

The apparatus allows measurements of absolute and relative permeabilities, wetting behaviour, changes in core microstructure, the effect of pH and adsorption/desorption of chemicals.

Laboratory testing capabilities were expanded to allow measurements of the phase behaviour of heavy oil/CO_2 systems in preparation for tests of heavy oil recovery by the CO_2 "huff'n'puff" stimulation process.

To determine whether CO_2 injection would be a suitable EOR technique at the Snipe Lake/Beaverhill Lake "A" Pool, several investigations were carried out at PRI.

The reservoir characteristics were studied, and the solubilities, bubble points, gas-oil ratios, swelling factors and viscosities of oil/CO_2 mixtures were measured at 85°C and at pressures up to 20 MPa. Slim-tube displacements and core displacements of oil by CO_2 were also performed, as were numerical simulations (CMG and INTERCOMP) of miscible flooding.

A realistic model of the reservoir was developed, which could be used as a basis for production forecasts using a gas-miscible process.

Sweep Improvement and Mobility Control by Polymer Flooding

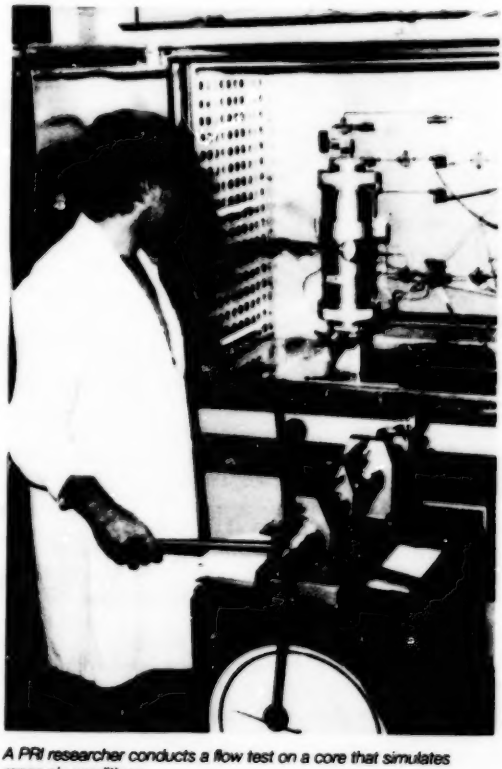
When water-soluble polymers are used in water-flooding processes, it is possible to achieve a relatively good volumetric sweep of the reservoir. In large volumes, polymer floods can provide mobility control; when they are introduced in small slugs, they can bring about changes in sweep patterns. As a consequence, polymer flooding is one of the most frequently used enhanced oil recovery methods, despite mixed results in the field.

Sometimes polymers that perform well in laboratory tests show no improvement in recovery rates in the field. At other times, results have been impressive. This disparity is believed to be caused by poor choices of candidate reservoirs and/or inadequate descriptions of reservoirs. To obtain a better understanding of the situation, PRI initiated studies to evaluate the interactions between polymers and reservoir rock and between polymers and reservoir fluids, while simultaneously preparing detailed descriptions of selected reservoirs.

Polymer flooding is generally used to: (1) correct an unfavourable water-oil mobility ratio that might occur during a water flood; (2) decrease the magnitude of permeability contrast in the reservoirs; (3) create a mobility buffer following a surfactant flood; and (4) improve surfactant slug mobility.

The desired decrease in water mobility results from an increase in the water viscosity, which is caused by the dissolved polymer, and a simultaneous decrease in the permeability of rock to water because the polymer is adsorbed on, and retained in, the reservoir. At PRI, laboratory assessments were made of the enhanced oil recovery potential of several polymers and then a field program was designed for the David Lloydminster "A" Pool. It comprised 40- to 80-acre five-spot patterns with six to eight injectors; cellulose derivatives of xanthan gums were used as polymers. These materials were chosen because of their tolerance of the high formation brine salinity.

In a second study, three mobility control polymers were selected and used in displacement tests that were part of an investigation of the Chauvin South Sparky "A" and "B" pools.



A PRI researcher conducts a flow test on a core that simulates reservoir conditions.

Polymer solutions or miscible gases were used to displace oil-containing cores maintained at reservoir conditions of temperature and pressure.

Polymers were compared on the basis of oil recovery efficiency, resistance factor development and the chemical composition of the reservoir rock. A preliminary economic evaluation of polymer-augmented water flooding of these pools indicated it can be economic with the existing well patterns, assuming five per cent more oil (relative to water flooding alone) would be produced over the life of the project. By using computer simulations of chemical flooding, along with considerable data from field and laboratory studies, investigations were made of polymers as: (1) materials that could plug gross channels; (2) agents to control mobility; and (3) a means of treating producing wells to reduce the water cut.

High Pressure Gas Miscible Project

An investigation was made of the suitability of using a high-pressure miscible nitrogen gas drive in the West Pembina Nisku Pool. Geological and petrophysical data from five of 20 Nisku Reef pools were examined, but the project was terminated when evidence was found of vertical barriers in the reservoir that would likely prevent downward displacement of oil by a miscible gas.

Subsequent Developments

In general terms, the sizeable body of research work conducted at PRI with financial support from A/CERRF has allowed the institute to make significant contributions to the science of enhanced oil recovery. This has been accomplished through such capabilities as geological modelling, reservoir analyses, polymer evaluations, tracer measurements, X-ray diffraction and electron microscope studies and computer modelling. The A/CERRF-funded work also resulted in two patents, namely U.S. 4 219 755 (''Oil Recovery Process'') and Canadian Patent 1 087 696 (''Back Pressure Regulator'').

Meanwhile, steam projects were initiated in the Bodo Upper Mannville 'B' Pool, and several oil companies have done polymer trials in various Alberta pools.

Further Reading

Batycky, J.P. and F.G. McCaffery. 1978. Low Interfacial Tension Displacement Studies. PRI Report RN-6.

Batycky, J.P. 1979. Dependence of Residual Oil Mobilization in Wetting and Roughness. PRI Report RP-41. Also as: Proceedings 3rd International Conference on Surface and Colloid Science, Stockholm, Sweden, August 1979, and in *Surface Phenomena in Enhanced Oil Recovery,* Editor: D.O. Shah, 1981, Plenum Publishing Corp., New York.

Batycky, J.P. 1981. Laboratory Testing of Polymers for Field Applications. PRI Report 1981-14.

Batycky, J.P. and B.B. Maini. 1982. A Study of the Application of Polymeric Gels in Porous Media. PRI Report 1982-2.

Collins, H.N., D. James, J.E. Senger and R. Timushka. 1976. Reserves of the Bodo Upper Mannville 'B' Pool with Particular Reference to Delineation of Gas Caps and Underlying Water Zones. PRI Report AR-1.

Collins, H.N., M. Hayashitani, Y. Yeung, J.P. Batycky and D. Moon. 1982. The Use of a Chemical Tracer in the Chauvin South Sparky 'A' and 'B' Pool. PRI Report 1982-5.

Collins, H.N., C. De Bree, A.A. Gross, Y. Ito and Y. Yeung. 1982. Sweep Improvement Study, Chauvin South Sparky 'A' and 'B' Pool Part 1: Reservoir Description, and Collins, H.N., C. De Bree, M. Hayashitani, T. Lim and J.P. Batycky. 1982. Part 2: Evaluation of Potential for Polymer Applications. PRI Report 1982-9.

Collins, H.N., C. De Bree and T.H. Lim. 1983. David Lloydminster 'A' Pool, Mobility Control by Polymer Flooding. PRI Report 1983-2.

Gross, A.A. 1981. A Geological Study of Three Mannville Sand Reservoirs, Chauvin South (Sparky 'A' and 'B'); Provost (Upper Mannville 'B'); and Bodo David (Lloydminster 'A') Pools. PRI Report 1981-5. Also as: paper 81-32-15, 32nd Annual Technical Meeting of the Petroleum Society of CIM, May 3-6, 1981.

Hayashitani, M. and W. Davis. 1981. Provost Upper Mannville 'B' Pool:

- Part 1 Provost Upper Mannville 'B' Steam Injection Project;
- Part 2 History Matching of Steam Project #2 in Provost Upper Mannville 'B' Pool;
- Part 3 Steam Injection Simulation for the Provost Upper Mannville 'B' Pool. PRI 1981-7.

Hayashitani, M., W. Davis, J. Novosad and J.P. Batycky. 1981. Numerical Simulation of Laboratory Steamflood Experiments. PRI Report 1981-1.

Lee, J.I. 1978. Miscibility of Carbon Dioxide-Sulphur Dioxide Hydrocarbon Systems. PRI Report RN-8.

Lee, J.I. and P.M. Sigmund. 1978. Phase Behavior and Displacement Studies of Carbon Dioxide-Hydrocarbon Systems. PRI Report RR-37.

Lee, J.I. 1979. Effectiveness of Carbon Dioxide Displacement Under Miscible and Immiscible Systems. PRI Report RR-40.

Lee, J.I. 1979. Viscosities of Carbon Dioxide-Sulphur Dioxide Mixtures and the Effect of Methane on Sulphur Dioxide Miscibility. PRI Report RN-9.

Lo, Hing Y. 1977. Laboratory Model Study of Steam Flood Oil Recovery. PRI Report IR-5.

Maini, B.B. and J.P. Batycky. 1980. Salinity and Hardness Tolerant Microemulsion Formulations. PRI Report RR-43.

Novosad, J. 1979. Adsorption of Pure Surfactant and Petroleum Sulphonate at the Solid-Liquid Interface. PRI Report RR-42. Also as: Proceedings 3rd International Conference on Surface and Colloid Science, Stockholm, Sweden, August 1979.

Novosad, J. 1981. Surfactant Retention in Berea Sandstone — Effects of Phase Behavior and Temperature. SPE Paper 10064, presented at the 56th Meeting of SPE, October, San Antonio, Texas.

Novosad, J., B.B. Maini and J.P. Batycky. 1982. A Study of Surfactant Flooding at High Salinity and Hardness. PRI Report 1982-7. Also as: Am. Oil Chem. Society Journal. 59: 833-839.

Novosad, J., L. Baxter and D. Moon. 1983. Laboratory Evaluation of Lignosulfonates as Sacrificial Adsorbates in Surfactant Flooding. PRI Report 1983-1. Also as: paper at CIM, 39th Meeting, May 10-13, 1983, Banff, Alberta.

Sayegh, S.G., J. Najman and B. Hlavacek. 1981. Phase Equilibrium and Fluid Properties of Pembina Cardium Stock-Tank Oil/Methane/Carbon Dioxide/Sulphur Dioxide Mixtures. PRI Report 1981-3. Also as: J. Can. Petr. Tech., 20: October-December, 1981.

Sayegh, S.G. and F.G. McCaffery. 1981. Laboratory Testing Procedures for Miscible Floods. 1981 European Symposium on Enhanced Oil Recovery, Bournemouth, England, September 21-23.

Sayegh, S.G. and J.E. Fosti. 1984. Oil Displacement by CO_2/SO_2 Mixtures. PRI Report 1984-1. Also as: Sayegh, S.G., F.F. Krause and J.E. Fosti. 1987. Miscible Displacement of Crude Oil by CO_2/SO_2 Mixtures. SPE Reservoir Engineering, May.

Sigmund, P.M. and F.G. McCaffery. 1977. An Improved Procedure for Determining the Relative Permeability Characteristics of Heterogeneous Porous Media. PRI Report RR-33.

Singhal, A.K. 1978. Physical Model Study of Inverted Seven Spot Steam Floods in a Pool Containing a Lloydminster Type Heavy Oil. PRI Report RR-38.

A Review for Gulf Canada Resources Inc. of the Snipe Lake/Beaverhill Lake 'A' Reservoir Description Developed by PRI, March 3, 1983

The Development of Water-Soluble Polymers for Enhanced Oil Recovery

Concurrent with PRI's laboratory and field examinations of commercially available polymers, attempts were made by Raylo Chemicals Limited of Edmonton to produce novel polymers which were specially designed and synthesized for use under the harsh conditions typical of Alberta's oil reservoirs.

This work was initiated because it was generally acknowledged that polymers used in enhanced oil recovery had been designed for some other purpose, but were being used in the oil field because they were readily available in large quantities. As a consequence, they exhibited shortcomings of one kind or another. For example, some underwent oxidative degradation when exposed to the elevated temperatures, oxygen and iron salts present in Alberta reservoirs. Others were not stable enough to withstand the shear forces exerted on them when they were forced under pressure down wells and into reservoirs. Still others reacted unfavourably when exposed to the dissolved salts found in the ancient sea brines that are associated with Alberta oil pools.

To overcome these limitations, Raylo carried out extensive laboratory tests on existing EOR polymers to ascertain which molecular characteristics were responsible for such properties as oxidative degradation, low brine tolerance and shear instability.

Polymers that were tested included polyacrylamides, partially hydrolysed polyacrylamides and polyethylene oxides, which are synthetic substances, and cellulose, xanthan gums and guar gums, which are naturally occurring polymers. Resistance to oxidation was measured initially by subjecting polymer solutions to attack by such oxidizing agents as hydrogen peroxide and ascorbic acid, but an accelerated screening test was devised, employing a mixture of sodium persulphate and sodium bisulphate, to generate the free radicals required in such oxidation reactions.

$$2\ Na_2S_2O_8 + Na_2SO_3 \longrightarrow$$

$$2\ SO_4^{-\cdot} + 3\ Na_2SO_4 + 2H^+$$

By using this test method, N-Hance 325 (a polymer commonly used in EOR work) was found to be well protected from oxidation when such antioxidants as formic acid, diethanolamine and a 2:1 mixture of thiourea and isopropanol were present.

To measure shear degradation, polymers were dissolved in dilute brine solutions (eight per cent total dissolved solids; Na:Ca:Mg ratios of 20:2:1) and forced under pressure through filters in a screen viscometer designed by Raylo.

After considerable testing of existing polymers, the investigators began attempts to modify polymers to produce substances exhibiting superior resistance to shear degradation and oxidation, while possessing good mobility control properties.

From considerations of molecular structure it was decided that grafting of polysaccharide polymers should achieve the desired properties. Before much progress was achieved in synthesizing these novel polymers, however, the project was terminated because of staff changes at Raylo.

Software for Computer-Assisted Petroleum Exploration

Computer-assisted reservoir simulation is one of the most sophisticated tools that petroleum companies can use to improve oil yields, whether conventional methods or enhanced oil recovery methods are used.

Before 1977, most reservoir simulation software was imported, but now Canadian oil companies, as well as overseas energy firms, are using software developed by a non-profit Alberta company.

The firm, Computer Modelling Group (CMG), was established in 1977 with initial funding from A/CERRF. During the past ten years, CMG has become self-supporting through services provided to member energy companies and agencies in eight countries.

Initially, CMG acquired several mathematical models of various oil recovery schemes, which had been developed by other computer software groups, but soon CMG began modifying them to suit Alberta's conditions.

Reservoir simulation work focused on:

- in situ combustion
- thermal processes
- water flooding
- polymer flooding
- hydrocarbon and/or non-hydrocarbon gas injection

Some real-life situations that occur in oil fields were modelled by CMG's computer specialists. For example, in complex recovery processes where interphase thermodynamic exchange is important, such as in enriched gas, high pressure gas and carbon dioxide displacement, the oil and gas can be anywhere from miscible to immiscible. A computer model was developed to simulate the phenomena related to these displacements and laboratory-scale carbon dioxide floods were simulated.

One element required in the simulation of reservoirs is the ability to predict reservoir gas and oil viscosities. In the early 1980s, enough modelling work had been done to make reliable predictions about reservoir gases, but the same could not be said for reservoir oils.

At CMG, mathematical models were developed that showed close correlations between predicted viscosities and those that were experimentally measured. The absolute deviation between the two sets of numbers was only 0.84 per cent.

Mixtures of carbon dioxide and sulphur dioxide have been tried as enhanced oil recovery agents because of their improved miscibility characteristics, their ability to closely match oil densities and viscosities and their increased oil swelling abilities. To accommodate the simulation of such systems, CMG tested the ability of certain mathematical equations to predict phase behaviour, and compared predictions with measurements that were made of actual systems at the Petroleum Recovery Institute. By making modifications to the equations, it was found that phase envelopes, vapour densities and swelling factors could be accurately predicted.

Similarly, after a mathematical method was devised to handle carbon dioxide solubility in the water present in the reservoir, CMG developed simulations of recovery schemes that use carbon dioxide in the injection gas.

These and other components of reservoir modelling evolved into several computer programs, which became available to CMG members during the period of A/CERRF support. Principal among them were:

ISCOM ..... to simulate in situ combustion processes

BLAKO ..... a black oil simulation

POLYMR .... used to simulate polymer flooding

MISIM 3 ..... to simulate recovery processes where interphase mass transfer is important

COMB ..... simulates combustion tube tests and is used to perform sensitivity studies

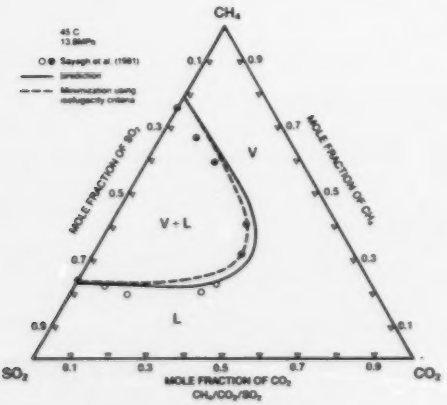
MISONE ..... can simulate laboratory-scale miscible-immiscible displacement experiments

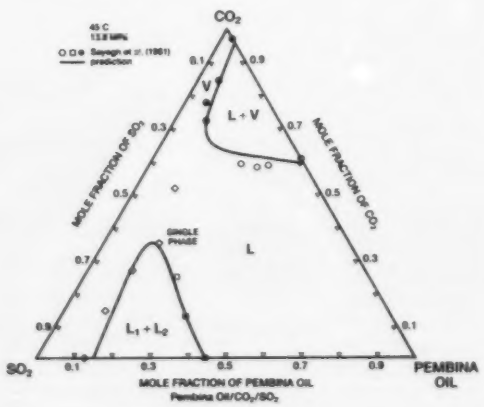
Subsequently, CMG has developed additional reservoir simulation programs and continues to transfer simulation technolcgy to member organizations.

In 1980, four U.S. oil companies, two software firms and CMG were asked to simulate an identical black oil recovery scheme using their respective reservoir models. The results were presented at The Gordon Conferences in Andover, New Hampshire. The results showed there was a high degree of consistency among the simulations. CMG's predictions approximated the mean of all the other simulations, thus demonstrating that CMG had developed skills that are competitive with the best in this specialized field.

Today, those same skills are made available to all of CMG's 33 members who benefit from participating in research efforts that are not limited to the interests of any one company, but are of value to the entire petroleum industry.

Predicted Versus Measured Phase Equilibrium Diagrams





(Source: *Phase Behavior Predictions of Oil/CO_2/SO_2 Mixtures Using the Peng-Robinson Equation of State*, Li, Y.K., L.X. Nghiem and S.G. Sayegh, Computer Modelling Group Report R7.05, February 1982.)

Further Reading

Au, A.D.K., A. Behie, B. Rubin and P.K.W. Vinsome. 1980. Techniques for Fully Implicit Reservoir Simulation. CMG.R10.02.

Behie, A. 1978. A Preliminary Evaluation of Direct Elimination Techniques for Reservoir Simulation Problems. CMG.R6.01.

Behie, A. and P.K.W. Vinsome. 1980. Block Iterative Methods for Fully Implicit Reservoir Simulation. CMG.RG.02.

Behie, A. and P.A. Forsyth Jr. 1981. Multi-Grid Solution of the Pressure Equation in Reservoir Simulation. CMG.R17.01.

Behie, A. and P.A. Forsyth Jr. 1982. Incomplete Factorization Methods. CMG.R6.03.

Behie, A. and P.A. Forsyth Jr. 1982. Direct and Iterative Solution Methods for Fully Coupled Wells. CMG.R6.04.

Behie, A. and P.A. Forsyth Jr. 1982. Multi-Grid Solution of Three-Dimensional Problems with Discontinuous Coefficients. CMG.R17.02.

Buchanan, W.L. 1983. A Preliminary Investigation of Modelling Steam Additives. CMG.R14.01.

Buchanan, W.L. and M. Raicar. 1983. Sensitivity Study of Field Scale Combustion Simulation for a Lloydminster-Type Heavy Oil Reservoir. CMG.CR.01.

Chiu, K.W. and J.W. Grabowski. 1978. Multiphase Flash Calculation in In Situ Combustion Simulation. CMG.R4.01.

Collins, D.A. and P.A. Forsyth Jr. 1983. Further Developments in Incomplete Factorization Methods. CMG.R6.06.

Coombe, D.A. 1982. A Fully Implicit Five Component Chemical Flood Simulator. CMG.R5.01.

Fong, David and Long X. Nghiem. 1980. A Viscosity Model for Reservoir Fluids. CMG.R7.02.

Ford, Gary G. 1982. Improvements in the Handling of Capillary Pressure and Relative Permeability in ISCOM. CMG.R4.05.

Forsyth Jr., P.A. 1980. Elimination of the Constraint Equation and Modelling of Problems with a Non-Condensable Gas in Steam Simulation. CMG.R9.01.

Forsyth Jr. P.A. and P. Sammon. 1982. Gas Phase Appearance and Disappearance in Fully Implicit Black Oil Simulation. CMG.R6.05.

Geshelin, Boris M. 1980. Static Fracture Model. CMG.R8.01.

Ko, S.C.M., W.L. Buchanan and P.K.W. Vinsome. 1980. A Critical Comparison of Finite-Difference Interblock Mobility Approximations in Numerical Reservoir Simulation. CMG.R1.01.

Li, Y.K., Long X. Nghiem and S.G. Sayegh. 1982. Phase Behavior Predictions of Oil/CO_2/SO_2 Mixtures Using the Peng-Robinson Equation of State. CMG.R7.05.

Li, Y.K. and Long X. Nghiem. 1982. The Development of a General Phase Envelope Construction Algorithm for Reservoir Fluid Studies. CMG.R12.01.

Nghiem, Long X. 1979. The Development of a One-Dimensional Miscible-Immiscible Simulator and Its Application in CO_2 Displacements. CMG.R2.02.

Nghiem, Long X. 1980. Compositional Modelling with an Equation of State. CMG. R7.01.

Nghiem, Long X. 1981. Modelling Infinite-Conductivity Vertical Fractures Using Source or Sink Terms. CMG.R8.02.

Nghiem, Long X. and D.K. Fong. 1981. A Method for Handling Gas Solubility in the Water Phase for Compositional Models. CMG.R7.04.

Nghiem, Long X., P.A. Forsyth Jr. and A. Behie. 1981. A Fully Implicit Hydraulic Fracture Model. CMG.R8.03.

Nghiem, Long X. and R.A. Heidemann. 1982. General Acceleration Procedure for Multiphase Flash Calculation with Application to Oil-Gas-Water Systems. CMG.R12.02.

Rubin, Barry, 1979. The Development of a Model for Pressure or Rate Constrained Wells Passing Through Several Grid Blocks. CMG.R11.01.

Rubin, Barry. 1980. The Generalized Crank-Nicholson Method for Reducing Time Truncation Errors in Reservoir Simulation. CMG.R4.04.

Rubin, Barry and A. Erian. 1982. Development of a Multilayer Implicitly Coupled Well Model. CMG.R11.02.

Sammon, P.H. and B. Rubin. 1982. Error Controlled Simulator Timestep Selection. CMG.R4.06.

Sammon, P.H. 1983. Heat Loss in Thermal Simulation and Its Connection with Error Controlled Timestep Selection. CMG.R4.07.

Siu, Alan L. and Long X. Nghiem. 1982. Fully Implicit Treatment of Infinite-Conductivity Vertical Fractures. CMG.R8.04.

Siu, Alan L. and Long X. Nghiem. 1982. On the Modelling of Non-Radial Flow Around Wells in Reservoir Simulation. CMG.R8.05.

Vinsome, P.K.W. 1980. Results for The Comparative Solution Project. CMG.R10.03.

Vinsome, P.K.W. 1980. The Method of Moments and Related Spin-Offs. CMG.R13.01.

Contacts

For more information about the various research studies conducted at the Petroleum Recovery Institute, contact:

Dr. Conrad Ayasse
Petroleum Recovery Institute
3512 - 33 Street, N.W.
Calgary, Alberta
T2L 2A6

Telephone: (403) 282-1211

Details regarding the development of new polymers for enhanced oil recovery applications may be obtained from:

Dr. J.F. Prescott
Technical Manager
Raylo Chemicals Limited
8045 Argyll Road
Edmonton, Alberta
T6C 4A9

Telephone: (403) 468-6060

For additional information about reservoir simulations and membership in Computer Modelling Group, contact:

Dr. Anthony Au
Manager, Business Development
Computer Modelling Group
3512 - 33 Street, N.W.
Calgary, Alberta
T2L 2A6

Telephone: (403) 282-9286

Additional copies of this publication are available from:

Information Centre
Alberta Energy/Forestry,
Lands and Wildlife
Main Floor, Bramalea Bldg.
9920 - 108 Street
Edmonton, Alberta
T5K 2M4

Telephone: (403) 427-3590

For more information about A/CERRF, contact:

Director, Energy Conservation
and Renewable Energy Research
Scientific and Engineering Services and Research Division
Alberta Energy
2nd Floor Pacific Plaza
10909 Jasper Avenue
Edmonton, Alberta
T5J 3M8

Telephone: (403) 427-8042